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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 16-06-013 (Filed June 30, 2016)

MOTION FOR ADOPTION OF SETTLEMENT AGREEMENT ON MARGINAL COST AND REVENUE ALLOCATION IN PHASE II OF PACIFIC GAS AND ELECTRIC COMPANY'S 2017 GENERAL RATE CASE

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Dated: October 26, 2017

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I. INTRODUCTION

Pursuant to Rule 11.1 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E) submits this Motion for Adoption of Settlement Agreement in Phase II of PG&E's 2017 General Rate Case (GRC) on Marginal Cost and Revenue Allocation Issues (MC/RA Settlement) on behalf of the MC/RA Settling Parties.[1/] By this motion, the MC/RA Settling Parties respectfully request Commission approval of the attached MC/RA Settlement Agreement (Attachment 1) that resolves the marginal cost and revenue allocation issues in this proceeding, subject to the mutually-agreed conditions, covenants and terms set forth therein.

1/ The MC/RA Settling Parties are: the Agricultural Energy Consumers Association (AECA); the California City-County Street Light Association (CAL-SLA); the California Farm Bureau Federation (CFBF); the California Large Energy Consumers Association (CLECA); the California Manufacturers & Technology Association (CMTA); the California State University; the Direct Access Customer Coalition (DACC); the Energy Producers and Users Coalition (EPUC); the Energy Users Forum (EUF); the Federal Executive Agencies (FEA); Marin Clean Energy (MCE); the Office of Ratepayer Advocates (ORA); Pacific Gas and Electric Company (PG&E); the Small Business Utility Advocates (SBUA); and The Utility Reform Network (TURN). Santa Clara County (SCC) and San Joaquin County (SJC), who participated actively in these settlement discussions, recently indicated they were each not in a position to sign the settlement at this time, in part because any decision to execute any settlement agreement must be made by the County Board of Supervisors, which requires significant lead-time to complete an open meeting process.

As described below, the MC/RA Settlement Agreement, which caps or limits the amount of PG&E's revenue requirement that is allocated to any customer class, is reasonable in light of the record as a whole, consistent with law, and in the public interest, and therefore should be adopted without modification.

II. PROCEDURAL HISTORY

On March 14, 2016, the CPUC approved PG&E's request for an extension of time to file its 2017 GRC Phase II Application. The extension revised the filing date from March 31, 2016 (pursuant to the CPUC's Rate Case Plan) to June 30, 2016.

On June 30, 2016, PG&E filed A.16-06-013 with its proposals for electric marginal costs, revenue allocation, and rate design. The application was protested on August 15, 2016, by: ORA; TURN; SSJID; jointly by AECA and CFBF; Modesto Irrigation District and Merced Irrigation District (MMID); SEIA; The Alliance for Solar Choice; the California Independent Petroleum Association (CIPA); and WMA.[2/]

A Prehearing Conference (PHC) was held on September 12, 2016, before then-assigned ALJ McKinney. The scope of issues and procedural schedule were set forth in the Scoping Memorandum and Ruling of Assigned Commissioner and Administrative Law Judge, dated October 19, 2016 (Scoping Memo).[3/] Per the Scoping Memo, PG&E filed its updated testimony,

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2/ A number of entities joined as parties after the close of the protest period, through motions requesting party status, which were granted, including SBUA, San Joaquin County, California Solar Energy Industry Association, SDG&E, Sierra Club, Santa Clara County, California Tomato Processors Association, City of Pittsburg, Santa Clara Valley Transportation Authority, and California State University.

3/ At the first PHC, there was substantial discussion about the approach and structure of a series of workshops ordered by D.15-07-001 to discuss the methodology to be used to develop any future residential fixed charge. The Scoping Memo set a "Procedural Schedule A" for a bifurcated earlier phase of this proceeding to consider those issues, including a series of workshops and filings. A Proposed Decision on these methodological issues was issued on August 2, 2017, with a final decision issued on October 4, 2017 (D.17-09-035). An additional issue, on an Energy Matinee Pricing Tariff pilot, was also bifurcated for an expedited decision that was issued on June 15, 2017 (D.15-06-004). The Scoping Memo called the traditional issues of marginal cost, revenue allocation and rate design, that are typically dealt with in a GRC Phase II proceeding, the "Non-Fixed Cost Phase" of this proceeding, and the procedural history of those is discussed above.

as required under the CPUC's Rate Case Plan, on December 2, 2016. ORA served its prepared testimony on February 15, 2017, on marginal cost, revenue allocation, and rate design. On March 15, 2017, seventeen intervenors served their prepared testimony: AECA, CAL-SLA, CFBF, CIPA, CLECA/CMTA, CTP, DACC, EPUC, EUF, FEA, MMID, SBUA, SEIA, SSJID, TURN, and WMA. On April 26, 2017, San Joaquin County (SJC) filed a motion to late-file testimony. PG&E responded on May 2, 2017, indicating that it had no objections to service of this additional testimony. On May 4, 2017, ALJ Cooke issued an e-mail ruling granting SJC's motion, and on May 19, 2017, SJC served its prepared direct testimony.

On March 31, 2017 and June 26, 2017, ALJ Cooke issued rulings granting the parties' joint requests for a continuance in the original schedule for Phase II of PG&E's 2017 GRC, in recognition of the parties' ongoing efforts to seek settlement, as discussed below.

III. SETTLEMENT HISTORY

Pursuant to the schedule set forth in the Scoping Memo, and Rule 12 of the CPUC's Rules of Practice and Procedure, on March 17, 2017, PG&E served the service list for this proceeding with a notice that an initial settlement conference would be held March 24, 2017. Immediately after that settlement conference, PG&E, on behalf of the parties, filed and served a Motion to Suspend Schedule for Rebuttal Testimony to Allow More Time for Settlement Discussions. ALJ Cooke issued an email ruling on March 31, 2017, granting the parties' request for a continuance in the schedule to allow for further settlement conferences, calling for settlement status reports to be filed on April 18, May 8, June 1, and June 22, 2017. On June 26, 2017, ALJ Cooke granted a further continuance in the schedule to allow the parties time for additional work on settlement of issues in this proceeding.

On June 15, 2017, the parties participating in settlement discussions reached an agreement in principle on the terms of this MC/RA Settlement Agreement. In the June 22, 2017 Settlement Status Report, PG&E notified ALJ Cooke that the active parties to the proceeding had reached settlement in principle on revenue allocation, and were completing discussions on a few related issues. As part of the joint settlement status reports filed in this proceeding, PG&E

informed ALJ Cooke that the parties were continuing separate settlement discussions among sub-groups of parties interested in the remaining GRC Phase II issues.

On June 26, 2017, ALJ Cooke issued a second ruling granting the parties' joint request for additional time to work on this MC/RA Settlement as well as and the other separate settlement discussions on rate design and other issues being conducted on parallel tracks. Status reports were filed on July 13, August 3, and August 24 in accordance with that Ruling. On September 9, 2017, PG&E filed a Supplement to Update Seventh Settlement Status Report. On September 14, 2017, PG&E filed its Eighth Status Report.

On September 18, 2017, the ALJ convened a telephonic prehearing conference to address procedural and scheduling matters. PG&E updated the ALJ and the parties about the status of its efforts to determine the causes for recently-discovered anomalies in certain bill impact analyses. PG&E reported that it had found two problems: (1) framing MV90 meter interval data into new TOU periods, and (2) an algorithm error affecting billing determinants in its rate design models. Both affect bill comparison calculations, and the second problem had a slight impact on revenue allocation.

During the telephonic PHC, the ALJ and parties discussed the impact on scheduling, and whether there were issues in the case that would not be affected by these developments. Master-meter discount, E-CREDIT and the DA/CCA Fees were identified as issues that should be able to move ahead without waiting for resolution of the bill comparisons and billing determinant issues. The ALJ and parties also agreed that another status report would be filed October 5, 2017. The ALJ set specific dates for these matters:

1. The next status report filing date was set for October 5;
2. The E-CREDIT and DA/CCA fee settlements were due no later than October 9; and

3. Master Meter rate design rebuttal testimony was set to be served on October 30, with hearings set for December 14 – 15, 2017.[4/]

Scheduling for the other issues in this proceeding was to be addressed when the uncertainty over availability of bill impact comparisons, and further developments in other settlement discussions, were resolved.

On October 5, 2017, PG&E filed the Ninth Settlement Status Report. On September 29, a second telephonic PHC was scheduled for October 17, 2017, to discuss scheduling issues. In an email ruling dated October 6, 2017, ALJ Cooke granted the parties' request to file a Tenth Settlement Status Report on October 16, 2017, in advance of the telephonic Prehearing Conference scheduled for October 17..

On October 9, 2017, PG&E filed, on behalf of the Settling Parties, the E-CREDIT and DA/CCA Fees Settlements, pursuant to the ALJ's established schedule, to enable a final decision on these two settlements to be issued on a bifurcated basis, prior to a Commission decision on the other remaining issues in this proceeding. The DA/CCA Settlement was also filed on October 9, 2017, as a supplement to the concurrent E-CREDIT Settlement. Since there were procedural developments thereafter, and because it will be proceeding on a different decisional time-line than the E-CREDIT and DA/CCA settlements, this MC/RA settlement is not being filed as supplement to the settlements on those bifurcated issues, on which a separate, early decision is being requested. Other rate design settlements that are filed after this MC/RA Settlement will be supplemental to the MC/RA Settlement.

On October 17, ALJ Cooke held a telephonic prehearing conference during which she established an updated schedule, which, among other things, included time for additional settlement discussions and two more status reports, on November 3 and December 4. On October 26, ALJ Cooke granted PG&E's request to move the Eleventh Status Report from November 3 to a November 10 deadline to file and serve.

4/ In an email dated October 2, WMA requested that new dates be set for rebuttal and hearings on master meter rate design issues. PG&E responded that it did not object to this scheduling request. ALJ Cooke ruled that this issue would be discussed at the October 17 telephonic prehearing conference.

IV. OVERVIEW OF SETTLEMENT TERMS[5/]

This MC/RA Settlement Agreement addresses three major issues: marginal costs, revenue allocation and rate changes between GRCs, each of which is summarized below. In addition, the parties have agreed to specific treatment for certain additional issues as described below.

A. Marginal Costs

Section VII of the MC/RA Settlement Agreement addresses marginal cost issues.

The MC/RA Settlement Agreement does not adopt any of the Settling Parties' marginal cost principles or proposals, except with regard to the specific marginal costs to be used solely for the purpose of establishing costs where needed for customer-specific contract analysis, including as required by Schedule E-31, and for contribution to margin for customers taking service on Schedule EDR.

In addition, while the revenue allocation agreement reached herein does not cover marginal costs, except as otherwise noted, certain marginal costs are necessary to develop any potential future residential fixed charge (and/or a minimum bill), if and when considered by the Commission. The Settling Parties anticipate that the Commission will consider proposals for adoption of a fixed charge (and/or a minimum bill) in the 2018 Rate Design Window (RDW) Proceeding. PG&E maintains that marginal costs are necessary for development of any proposed residential fixed charge (and/or a minimum bill), including: distribution capacity and customer access marginal costs and related factors necessary to derive the distribution Equal Percentage of Marginal Cost (EMPC). However, in this GRC Phase II proceeding, the Settling Parties have reached an impasse and have not been able to agree either on actual marginal cost values or on which categories of marginal costs need to be litigated in this proceeding. The Settling Parties agree that a Prehearing Conference, to be held in the near future in this GRC Phase II

5/ This section of the Motion summarizes the fundamental components of the MC/RA Settlement Agreement and necessarily simplifies some of the terms. To the extent that there is any conflict between the exact wording of the Settlement Agreement and this motion, the attached MC/RA Settlement Agreement should govern.

proceeding, is an appropriate venue to consider the scope of marginal cost issues that need to be litigated, and any further procedural steps on the issue of marginal costs for fixed charges (and/or a minimum bill) that need to be considered in this proceeding. The Settling Parties further agree that any marginal cost components (and related factors) developed and adopted in this proceeding for the purpose of future calculations of a potential residential fixed charge (and/or a minimum bill) shall have no precedential value with respect to the revenue allocation or development of non-residential rate design.

B. Revenue Allocation

Section VIII of the MC/RA Settlement Agreement addresses revenue allocation issues, both for the initial allocation after the final decision in this proceeding, as well as for revenue allocation between rate cases (discussed in section C of this Motion). The Settling Parties generally agree that electric revenue should be allocated on an overall revenue-neutral basis to preserve then-current total authorized revenue. Considering and both recognizing and compromising the litigation positions taken by the individual parties, the Settling Parties agree to the revenue allocation set forth in the MC/RA Settlement Agreement, starting with the initial, bundled and Direct Access/Community Choice Aggregation (DA/CCA) percentage changes summarized below:

Bundled Class	Percent Change
Residential	-0.45%
Small Light & Power	-0.02%
Medium Light & Power	-0.27%
E-19	0.23%
Streetlight	0.70%
Standby	-0.70%
Agricultural	0.70%
E-20T	0.70%
E-20P	0.42%
E-20S	-0.01%
Total Bundled	-0.08%

DA/CCA Class	Percent Change
Residential	0.62%
Small Light & Power	0.42%
Medium Light & Power	0.67%
E-19	0.69%
Streetlight	1.40%
Standby	-1.40%
Agricultural	1.40%
E-20T	1.25%
E-20P	0.68%
E-20S	-0.13%
FPP T[2]	5.23%
FPP P[2]	3.33%
FPP S[2]	3.34%
Total DA/CCA	0.66%

This agreed revenue allocation reflects the Settling Parties' agreement to limit the amount of PG&E's revenue requirement that is allocated to any customer class using agreed caps and floors in order to mitigate potentially adverse impacts on any particular customer class.

The MC/RA Settlement Agreement further provides that, while PG&E will target the average percentage change for every customer group at the levels shown in Table 1 of the MC/RA Settlement Agreement, the actual results may vary in a small way based on rate changes that may occur before the MC/RA Settlement Agreement is implemented. The revenue allocation amounts, percentages, and procedures agreed to in this MC/RA Settlement Agreement mitigate potentially adverse impacts on any particular customer class.

C. Rate Changes Between GRCs

Section VIII.3 of the MC/RA Settlement Agreement addresses rate changes between GRCs. After rates are implemented pursuant to the Commission's final decision on marginal costs, revenue allocation and most rate design issues in this proceeding,[6] the MC/RA Settling Parties agree that future changes in rates to reflect changes to the revenue requirement will also be made in the manner set forth in the MC/RA Settlement Agreement. Specifically, each customer group will be allocated the average percentage change in functional revenue necessary to collect the functional revenue requirement. Except as specifically noted in the MC/RA Settlement Agreement, this will be accomplished by implementing changes to the revenue requirement for each component by applying to each rate schedule the same percentage change to rates by component required to collect the revenue requirement for that component.

D. Other Issues

Section IX of the MC/RA Settlement Agreement addresses two additional issues. First, PG&E has agreed to provide certain data to AECA and CFBF for possible use in the 2020 GRC Phase II proceeding. Second, this Settlement Agreement excludes consideration of Agricultural Parties' claims of deviations between the estimated forecast for Agricultural Class revenue responsibility and revenue collected from the Agricultural Class based on unexpectedly high agricultural sales during recent drought years (prior to 2016). The Settling Parties agree that this issue will be litigated and subject to the normal litigation process, including rebuttal testimony, hearings if necessary, and briefs.

V. THE COMMISSION SHOULD ADOPT THE MC/RA SETTLEMENT AGREEMENT

A. Commission Policy Favors Settlements

The Commission has a history of supporting settlement of disputes if they are fair and reasonable in light of the whole record.[7] As the Commission has reiterated over the years, the "Commission favors settlement because they generally support worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties

6/ Other than the E-CREDIT rate design and DA/CCA Fees Settlements that were filed on October 9, 2017 requesting a bifurcated, earlier CPUC decision.

7/ D.05-03-022, mimeo, pp. 7-8, *citing* D.88-12-083 (30 CPUC 2d 189, 221-223) and D.91-05-029 (40 CPUC 2d. 301, 326).

to reduce the risk that litigation will produce unacceptable results."[8/] This strong public policy favoring settlements weighs in favor of the Commission resisting the temptation to alter the results of the negotiation process. As long as a settlement taken as a whole is reasonable in light of the record, consistent with the law, and in the public interest, it should be adopted.[9/]

Each portion of this MC/RA Settlement Agreement is dependent upon the other portions of that same agreement. Changes to one portion of the MC/RA Settlement Agreement would alter the balance of interests and the mutually agreed upon compromises and outcomes contained in the MC/RA Settlement Agreement. As such, the MC/RA Settling Parties request that this MC/RA Settlement Agreement be adopted as a whole by the Commission, without modification.

B. The MC/RA Settlement Agreement is an All-Party Settlement

To qualify as an all-party settlement, the sponsoring parties must show that a settlement meets the following four conditions:

1. The settlement agreement commands the unanimous sponsorship of all active parties to the proceeding;
2. The sponsoring parties are fairly reflective of the affected interests;
3. No term of the settlement contravenes statutory provisions or prior Commission decisions; and
4. The settlement conveys to the Commission sufficient information to permit it to discharge its future regulatory obligations with respect to the parties and their interests.

8/ D.10-12-035, 2010 Cal PUC LEXIS 467 at *87; *and see* D.05-03-022, mimeo, p. 8, citing D.92-12-019, 46 CPUC 2d 538, 553. *See also* D.10-12-051, 2010 Cal. PUC LEXIS 566 at *55 (Commission decisions "express the strong public policy favoring settlement of disputes if they are fair and reasonable"); D.10-11-035, 2010 Cal. PUC LEXIS 495 at *17 (the Commission's longstanding policy favoring settlement…reduces litigation expenses, conserves scarce Commission resources…" *and see* D.10-11-011, 2010 Cal. PUC LEXIS 533 at *50 ("There is a strong public policy favoring the settlement of disputes to avoid costly and protracted litigation.").

9/ *See, generally,* D.05-03-022, mimeo, pp. 7-13.

This MC/RA Settlement meets the first condition because the Settling Parties represent all active parties who submitted testimony in the issues in this proceeding that are the subject of this MC/RA Settlement Agreement.[10/] This agreement meets the second condition because the parties to it fairly represent the interests of the parties affected by it. That is AECA, CAL-SLA, CFBF, CLECA, CMTA, CSU, DACC, EPUC, EUF, FEA, MCE, ORA, PG&E, SBUA, and TURN fairly represent the interests of the wide variety of types of customers and customer classes that are affected by revenue allocation and marginal cost issues. This settlement meets the third condition because the terms of this agreement are consistent with law. Finally, this MC/RA Settlement Agreement meets the fourth condition because the record will contain the prepared testimony of all the parties on marginal cost and revenue allocation, and because the MC/RA Settlement Agreement contains detailed descriptions regarding the timing of rate changes and the manner in which the Settlement Agreement is to be implemented between GRCs.

C. The MC/RA Settlement Agreement is Reasonable in Light of the Record as a Whole.

The Commission should adopt this MC/RA Settlement Agreement because it represents a reasonable compromise of the parties' positions as reflected in the record as a whole in this proceeding. Prior to the settlement, parties conducted discovery and served testimony on MC/RA issues.[11/] The Settling Parties' agreement represents reasonable compromises after careful review and discussion by all interested parties of the wide variety of MC/RA proposals

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10/ Active parties to this proceeding who did not sign this MC/RA Settlement Agreement, such as Santa Clara Valley Transit Authority, Solar Energy Industries Association (SEIA), and the Western Manufactured Housing Communities Association (WMA) were aware of the MC/RA Agreement and have affirmatively indicated they do not oppose it. The situation, as here, where all of the active parties who filed testimony on MC/RA subjects have either signed the MC/RA Settlement or stated they do not oppose it, is adequate, under Rule 12.1 of the CPUC's Rules of Practice and Procedure, "settlements need not be joined by all parties." Indeed the CPUC approved such MC/RA settlements in PG&E's 2011 and 2014 GRCs (approved in D. 11-05-047 and D.15-08-005 respectively).

11/ *See, e.g.*, the December 2, 2016 Updated Direct Testimony in Exhibits PG&E-8 (Chapters 1, 2, and 3) and all of PG&E-9; the February 15, 2017 Prepared Direct Testimony of ORA, and the March 15, 2017 Prepared Direct Testimonies of the intervenors participating in this settlement.

presented in the parties' prepared testimony, after incorporating appropriate revisions and updates. This is illustrated by the comparison exhibit PG&E and ORA will jointly serve, no later than December 22, 2017, showing the impact of the MC/RA Settlement Agreement in relation to their respective litigation positions, as required by Rule 12.1(a). In addition, during settlement negotiations, the Settling Parties also carefully conducted and/or reviewed numerous modeling runs and requested and received other information to help them analyze each of the issues resolved in this settlement. This MC/RA Settlement Agreement was reached only after substantial give-and-take in arms-length negotiations, and after each party had made significant concessions to resolve issues in a manner that reflects a reasonable compromise of their litigation positions.[12/]

The prepared testimony submitted in this proceeding, this Motion, and the attached MC/RA Settlement, contains sufficient information for the Commission to judge the reasonableness of the MC/RA Settlement Agreement, and for the Commission to discharge any future regulatory obligations with respect to this matter.

D. The MC/RA Settlement Agreement is Consistent with Law

In addition, this MC/RA Settlement Agreement is consistent with current law, as it complies with all applicable statutes and prior Commission decisions. These include Public Utilities Code Section 451, which requires that utility rates must be just and reasonable.

E. The MC/RA Settlement Agreement is in the Public Interest.

Finally, the MC/RA Settlement Agreement is in the public interest. This agreement is a reasonable compromise of the Settling Parties' respective positions, and is in the public interest as well as in the interest of PG&E's customers. Resolution of the issues and their outcome was achieved through participation and consideration of various allocation options – over the course of about two dozen settlement conference calls or meetings over a five month period – by representatives of a broad range of customer groups taking service on PG&E's system, resulting

12/ D.13-11-003, mimeo, pp. 6-7; D. 13-07-029, mimeo, pp. 7-8; D.13-12-045, mimeo, pp. 10-11.

in a balanced settlement for all ratepayers. It fairly resolves issues and provides more certainty to customers regarding their present and future costs, which is in the public interest. The MC/RA Agreement, if adopted by the Commission, avoids the time expense and uncertainty associated with further litigating these issues,[13/] and frees up Commission resources for other proceedings (as well as other issues in this proceeding). Given that the Commission's workload is extensive, the impact on Commission resources is doubly important. This MC/RA agreement frees up the time and resources of other parties as well, so that they may focus on other proceedings (or other issues in this proceeding) that impact their constituencies.

F. The MC/RA Settlement Agreement is a Careful Balance of Interests Based on Agreed Compromise and Should Be Construed as an Integrated Whole.

Each portion of the MC/RA Settlement Agreement is dependent upon the other portions of the agreement. Changes to one portion of the MC/RA Settlement Agreement would alter the balance of interests and the mutually agreed upon compromises and outcomes which are contained in the agreement. To accommodate the interests related to diverse issues, the compromises made by Settling Parties in one section of this MC/RA agreement resulted in changes, concessions, or compromises by the Settling Parties in other sections. As such, the Settling parties request that the MC/RA Settlement Agreement be adopted as a whole by the Commission, without modification, as it is reasonable in light of the whole record, consistent with law, and in the public interest.

13/ D.13-11-003, mimeo, p. 8; D.13-12-045, mimeo, p. 12.

VI. CONCLUSION

For the reasons set forth above, PG&E respectfully moves the Commission for an order that:

1. Finds the attached MC/RA Settlement Agreement to be reasonable in light of the whole record, consistent with law, and in the public interest;
2. Adopts the attached MC/RA Settlement Agreement without modification;
3. Authorizes PG&E to implement changes in rates in accordance with the terms of the Settlement Agreement; and
4. Grants such other relief as is necessary and proper.

Respectfully submitted,

By: *___/s/ Gail L. Slocum___*
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On Behalf of the MC/RA Settling Parties

Dated: October 26, 2017

Appendix A

SETTLEMENT AGREEMENT IN PHASE II OF PACIFIC GAS AND ELECTRIC COMPANY'S 2017 GENERAL RATE CASE ON MARGINAL COST AND REVENUE ALLOCATION ISSUES

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Appendix A

SETTLEMENT AGREEMENT IN PHASE II OF PACIFIC GAS AND ELECTRIC COMPANY'S 2017 GENERAL RATE CASE ON MARGINAL COST AND REVENUE ALLOCATION ISSUES

I. INTRODUCTION

In accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC or Commission), the parties to this Settlement Agreement (Settling Parties) agree on a mutually acceptable outcome to the marginal cost and revenue allocation issues in Application (A.) 16-06-013, PG&E's 2017 General Rate Case (GRC) Phase II. The details of this Marginal Cost and Revenue Allocation (MC/RA) Settlement Agreement are set forth herein.

This MC/RA Settlement Agreement is a direct result of the Administrative Law Judges' (ALJ)[1/] and Assigned Commissioner's facilitation for the active parties to meet and seek a workable compromise. The active parties hold differing views on numerous aspects of PG&E's initial marginal cost and revenue allocation proposals in Phase II of this General Rate Case (GRC) proceeding. However, the Parties bargained earnestly and in good faith to seek a compromise and to develop this MC/RA Settlement Agreement, which is the product of arms-length negotiations among the Settling Parties on a number of disputed issues. These negotiations considered the interests of all of the active parties on marginal cost and revenue allocation issues, and the MC/RA Settlement Agreement addresses each of these interests in a fair and balanced manner.

The Settling Parties developed this MC/RA Settlement Agreement by mutually accepting concessions and trade-offs among themselves. Thus, the various elements and sections of this MC/RA Settlement Agreement are intimately interrelated, and should not be altered, as the Settling Parties intend that this Settlement Agreement be treated as a package solution that strives to balance and align the interests of each party. Accordingly, the Settling Parties

1/ Originally this Application was assigned to ALJ McKinney. Subsequently, the CPUC reassigned this case to ALJs Cooke and Atamturk. The Assigned Commissioner is Peterman.

respectfully request that the Commission promptly approve the MC/RA Settlement Agreement without modification. Any material change to the MC/RA Settlement Agreement shall render it null and void, unless all of the Settling Parties agree in writing to such changes.

II. SETTLING PARTIES

The Settling Parties are as follows[2/]:

- Agricultural Energy Consumers Association (AECA);
- California City-County Street Light Association (CAL-SLA);
- California Farm Bureau Federation (CFBF);
- California Large Energy Consumers Association (CLECA);
- California Manufacturers & Technology Association (CMTA);
- California State University
- Direct Access Customer Coalition (DACC);
- Energy Producers and Users Coalition (EPUC);
- Energy Users Forum (EUF);
- Federal Executive Agencies (FEA);
- Marin Clean Energy (MCE)
- Office of Ratepayer Advocates (ORA);
- Pacific Gas and Electric Company (PG&E);
- Small Business Utility Advocates (SBUA); and
- The Utility Reform Network (TURN).

2/ Although the following parties have not joined the MC/RA Settlement Agreement, they have, nonetheless, affirmatively indicated that they do not oppose the Agreement, as presented herein: Santa Clara Valley Transit Authority, Solar Energy Industries Association (SEIA), and the Western Manufactured Housing Communities Association (WMA). Santa Clara County and San Joaquin County, who participated actively in these settlement discussions, recently indicated they were not in a position to sign the settlement at this time, in part because any decision to execute any settlement agreement must be made by their County Board of Supervisors, which requires significant lead-time to complete an open meeting process.

III. SETTLEMENT CONDITIONS

This MC/RA Settlement Agreement resolves the issues raised by the Settling Parties in A.16-06-013 (Phase II), on marginal costs and revenue allocation, subject to the conditions set forth below:

1. This MC/RA Settlement Agreement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters.
2. This MC/RA Settlement Agreement represents a negotiated compromise among the Settling Parties' respective litigation positions on the matters described, and the Settling Parties have assented to the terms of the MC/RA Settlement Agreement only to arrive at the agreement embodied herein. Nothing contained in the MC/RA Settlement Agreement should be considered an admission of, acceptance of, agreement to, or endorsement of any disputed fact, principle, or position previously presented by any of the Settling Parties on these matters in this proceeding.
3. This MC/RA Settlement Agreement does not constitute and should not be used as a precedent regarding any principle or issue in this proceeding or in any future proceeding.
4. The Settling Parties agree that this MC/RA Settlement Agreement is reasonable in light of the testimony submitted, consistent with the law, and in the public interest.
5. The Settling Parties agree that the language in all provisions of this MC/RA Settlement Agreement shall be construed according to its fair meaning and not for or against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.
6. The Settling Parties agree that this MC/RA Settlement Agreement addresses all marginal cost and revenue allocation issues. However, any marginal costs used in this settlement have no precedent and any marginal costs adopted for a specific purpose within this settlement or any other settlement in this proceeding have no binding precedent on the use of marginal costs for any other purposes by PG&E, except as provided in this

Agreement.

7. This MC/RA Settlement Agreement may be amended or changed only by a written agreement signed by the Settling Parties.
8. The Settling Parties shall jointly request Commission approval of this MC/RA Settlement Agreement and shall actively support its prompt approval. Active support shall include written and/or oral testimony (if testimony is required), briefing (if briefing is required), comments and reply comments on the proposed decision,[3/] advocacy to Commissioners and their advisors as needed, and other appropriate means as needed to obtain the requested approval.
9. The Settling Parties intend the MC/RA Settlement Agreement to be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies this MC/RA Settlement Agreement, in whole or in part, the Settling Parties reserve their rights under Rule 12.4 of the CPUC's Rules of Practice and Procedure, and the MC/RA Settlement Agreement should not be admitted into evidence in this or any other proceeding. Any material change to the MC/RA Settlement Agreement shall render it null and void, unless all of the Settling Parties agree in writing to such changes. Therefore, any Settling Party not in agreement with any modification or rejection of any term or condition of the MC/RA Settlement Agreement will not be bound whatsoever by the MC/RA Settlement Agreement's terms or conditions.

IV. OVERALL PROCEDURAL HISTORY

On March 14, 2016, PG&E requested, and the CPUC approved an extension of time to file its Application in Phase II of the 2017 GRC. The extension revised the filing date from March 31, 2016 (as required under the CPUC's Rate Case Plan) to June 30, 2016.

On June 30, 2016, PG&E filed, in A.16-06-013, its proposals related to electric marginal costs, revenue allocation, and rate design.

3/ Any oral and written testimony that the CPUC might require may be prepared and submitted jointly among parties with similar interests.

The application was protested on August 15, 2016, by: ORA; TURN; SSJID; jointly by AECA and CFBF; Modesto Irrigation District: Merced Irrigation District; SEIA; the Alliance for Solar Choice; the California Independent Petroleum Association; and WMA.[4/]

A prehearing conference (PHC) was held on September 12, 2016, before then-assigned ALJ McKinney. The scope of issues and procedural schedule were set forth in the Scoping Memorandum and Ruling of Assigned Commissioner and Administrative Law Judge, dated October 19, 2016 (Scoping Memo).[5/] Per the Scoping Memo, PG&E filed its updated testimony, as required under the CPUC's Rate Case Plan, on December 2, 2016. ORA served its prepared testimony on February 15, 2017, on marginal cost, revenue allocation, and rate design. On March 15, 2017, seventeen intervenors served their prepared testimony: AECA, CAL-SLA, CFBF, CIPA, CLECA/CMTA, CTP, DACC, EPUC, EUF, FEA, MMID, SBUA, SEIA, SSJID, TURN, and WMA. On April 26, 2017, San Joaquin County (SJC) filed a motion to late-file testimony. PG&E responded on May 2, 2017, indicating that it had no objections to service of this additional testimony. On May 4, 2017, ALJ Cooke issued an e-mail ruling granting SJC's motion, and on May 19, 2017, SJC served its prepared direct testimony.

On March 31, 2017 and June 26, 2017, ALJ Cooke issued rulings granting the parties' joint requests for a continuance in the original schedule for Phase II of PG&E's 2017 GRC, in

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4/ A number of entities joined as parties after the close of the protest period, through motions requesting party status, which were granted, including SBUA, San Joaquin County, California Solar Energy Industry Association, SDG&E, Sierra Club, County of Santa Clara, California Tomato Processors Association, City of Pittsburg, Santa Clara Valley Transportation Authority, and California State University.

5/ At the first PHC, there was substantial discussion about the approach and structure of a series of workshops ordered by D.15-07-001 to discuss the methodology to be used to develop any future residential fixed charge. The Scoping Memo set a "Procedural Schedule A" for a bifurcated earlier phase of this proceeding to consider those issues, including a series of workshops and filings. A Proposed Decision on these methodological issues was issued on August 2, 2017, with a final decision issued on October 4, 2017 (D.17-09-035). An additional issue, on an Energy Matinee Pricing Tariff pilot, was also bifurcated for an expedited decision that was issued on June 15, 2017 (D.17-06-004). The Scoping Memo called the traditional issues of marginal cost, revenue allocation and rate design, that are typically dealt with in a GRC Phase II proceeding, the "Non-Fixed Cost Phase" of this proceeding, and the procedural history of those issues is discussed above.

recognition of the parties' ongoing efforts to seek settlement, as discussed below.

V. SETTLEMENT HISTORY

Pursuant to the schedule set forth in the Scoping Memo, and Rule 12 of the CPUC's Rules of Practice and Procedure, on March 17, 2017, PG&E served the service list for this proceeding with a notice that an initial settlement conference would be held March 24, 2017. Immediately after that settlement conference, PG&E on behalf of the parties, filed and served a Motion to Suspend Schedule for Rebuttal Testimony to Allow More Time for Settlement Discussions. ALJ Cooke issued an email ruling on March 31, 2017, granting the parties' request for a continuance in the schedule to allow for further settlement conferences, and calling for settlement status reports to be filed on April 18, May 8, June 1, and June 22, 2017.

On June 15, 2017, the parties participating in settlement discussions reached an agreement in principle on the terms of this MC/RA Settlement Agreement. In the June 22, 2017 Status Report, PG&E notified ALJ Cooke that the active parties to the proceeding had reached settlement in principle on revenue allocation, and were completing discussions on a few related issues. As part of the joint settlement status reports filed in this proceeding, PG&E informed ALJ Cooke that the parties were continuing separate settlement discussions among sub-groups of parties interested in the remaining GRC Phase II issues.

On June 26, 2017, ALJ Cooke granted a further continuance in the schedule to allow the parties time for additional work on settlement of the remaining issues in this proceeding. Pursuant to that ruling, PG&E filed additional settlement status reports on July 13, August 3, August 24, a Supplement to Update the Seventh Status Report on September 9, and the Eighth Settlement Status Report on September 14, 2017.

On September 18, 2017, the ALJ convened a telephonic prehearing conference to address procedural and scheduling matters. PG&E updated the ALJ and the parties about the status of its efforts to determine the causes for recently-discovered anomalies in certain bill impact analyses. PG&E reported that it had found two problems: (1) framing MV90 meter interval data into new TOU periods, and (2) an algorithm error affecting billing determinants in its rate design models.

Both affect bill comparison calculations, and the second problem had a slight impact on revenue allocation.

During the telephonic PHC, the ALJ and parties discussed the impact on scheduling, and whether there were issues in the case that would not be affected by these developments. Master-meter discount, E-CREDIT and the DA/CCA Fees were identified as issues that should be able to move ahead without waiting for resolution of the bill comparisons and billing determinant issues. The ALJ and parties also agreed that another status report would be filed October 5, 2017. The ALJ set specific dates for these matters:

1. The next status report filing date was set for October 5;
2. The E-CREDIT and DA/CCA fee settlements were due no later than October 9; and
3. Master Meter rate design rebuttal testimony was set to be served on October 30, with hearings set for December 14 – 15, 2017.[6/]

Scheduling for the other issues in this proceeding was to be addressed when the uncertainty over availability of bill impact comparisons, and other settlement discussions, was resolved.

On October 5, 2017, PG&E filed the Ninth Settlement Status Report. On September 29, a second telephonic PHC was scheduled for October 17, 2017, to further discuss scheduling issues. In an email ruling dated October 6, 2017, ALJ Cooke granted the parties' request to file a Tenth Settlement Status Report on October 16, 2017, in advance of the October 17, 2017 telephonic PHC.

On October 9, 2017, PG&E filed, on behalf of the Settling Parties, the E-CREDIT and DA/CCA Fees Settlements, pursuant to the ALJ's established schedule. These early filings would enable the Commission to issue a final decision on those two settlements on a bifurcated basis, prior to a Commission decision on the other remaining issues in this proceeding.

6/ In an email dated October 2, WMA requested that new dates be set for rebuttal and hearings on master meter rate design issues. PG&E responded that it did not object to this scheduling request. ALJ Cooke ruled that this issue would be discussed at the October 17 telephonic prehearing conference.

On October 17, ALJ Cooke held a telephonic Prehearing Conference at which she established an updated schedule, which among other things included time for additional settlement discussions and two more status reports, on November 3 and December 4. On October 26, ALJ Cooke granted PG&E's request to move the Eleventh Status Report from November 3 to a November 10 deadline to file and serve.

VI. SETTLEMENT TERMS

Considering and both recognizing and compromising the litigation positions taken by the individual parties, the Settling Parties agree to the revenue allocation set forth in this MC/RA Settlement Agreement. The revenue allocation amounts, percentages, and procedures agreed to in this MC/RA Settlement Agreement are reasonable and based on the record in this proceeding.

No later than December 22, 2017, PG&E and ORA will jointly serve a comparison exhibit showing the impact of the MC/RA Settlement Agreement in relation to their respective litigation positions, as required by Rule 12.1(a).

The Settling Parties agree that all testimony served prior to the date of this MC/RA Settlement Agreement that addresses the issues resolved by this MC/RA Settlement Agreement should be admitted into evidence without cross-examination by the Settling Parties.

The Settling Parties further agree to try to reach agreement on additional issues in A.16-06-013 including the remaining residential rate design issues, and non-residential rate design issues (including RES-BCT program issues) that are not resolved by this MC/RA Settlement Agreement, as explained in more detail in the periodic Settlement Status Reports filed with the CPUC by PG&E on behalf of the interested parties.[7/]

7/ PG&E is still conducting separate settlement discussions in the areas of: (1) residential rate design, (2) small light and power rate design, (3) medium and large light and power rate design, (4) agricultural rate design, (5) standby rate design, (6) economic development rates, (7) DA/CCA Fees, (8) Schedule E-Credit, (9) the Master Meter Discount, (10) streetlight rate design, (11) TOU transition issues and (12) RES-BCT rate design. TOU period issues will be discussed in the follow-up settlement areas listed above, where applicable. If and as settlements are reached on the various rate design issues listed above, they will be submitted as supplements to this Settlement, as was done in PG&E's TY 2011and 2014 GRC Phase II proceedings.

The Settling Parties each acknowledge and agree they will not use, allege or argue that any of the terms or conditions of this Settlement Agreement (in whole or in part) pre-empt, constrain, limit or should determine the outcome content or scope of any negotiations, settlement or litigation in this GRC Phase II proceeding relating to the RES-BCT program [8/] rate design or TOU periods, or both. The Settling Parties who are RES-BCT program customers will not propose or recommend a modification of this Settlement Agreement in this GRC Phase II proceeding.

VII. MARGINAL COSTS SETTLEMENT

The Settling Parties agree that this MC/RA Settlement Agreement addresses all necessary marginal cost issues as specifically mentioned below.

(1) This MC/RA Settlement Agreement does not adopt any of the Settling Parties' marginal cost principles or proposals as the basis for the Revenue Allocation settlement described in Section VIII below.

(2) This MC/RA Settlement Agreement adopts marginal costs to be used solely for the purpose of establishing costs where needed for customer-specific contract analysis, including as required by Schedule E-31, and for analysis of contribution to margin for customers taking service under Schedule EDR. The marginal costs to be used for these analyses are provided in Attachment 1 to this MC/RA Settlement Agreement.

(3) In response to testimony by ORA, PG&E agrees to provide Revenue Cycle Services values for the most recently available three years as part of its next GRC Phase II. That information may then be used by the parties for validation of, or setting the values for, Revenue Cycle Services (at their discretion) in the next GRC.

8/ The Renewable Energy Self-Generation Bill Credit Transfer (“RES-BCT”) program was created by the Commission pursuant to a legislative requirement in Public Utilities Code Section 2830. That legislation required the utilities to provide certain government agencies, universities and school districts, cities and counties, that have one or more eligible renewable generation facilities, the ability to export the energy from those eligible renewable generation facilities to the grid and receive generation credits at the generation-only rate for such renewable energy, as a bill credit to benefit the same government entity’s other facilities’ utility accounts (the benefiting accounts). This program is subject a cap of 105.25 MW of generating capacity in PG&E’s service territory.

(4) While the revenue allocation agreement reached herein does not cover marginal costs, except as otherwise noted, certain marginal costs are necessary to develop any potential future residential fixed charge (and/or a minimum bill), if and when considered by the Commission. The Settling Parties anticipate that the Commission will consider proposals for adoption of a fixed charge (and/or a minimum bill) in the 2018 Rate Design Window (RDW) Proceeding. PG&E maintains that marginal costs are necessary for development of any proposed residential fixed charge (and/or a minimum bill), including: distribution capacity and customer access marginal costs and related factors necessary to derive the distribution Equal Percentage of Marginal Cost (EMPC). However, in this GRC Phase II proceeding, the Settling Parties have reached an impasse and have not been able to agree either on actual marginal cost values or on which categories of marginal costs need to be litigated in this proceeding. The Settling Parties agree that a Pre-Hearing Conference, to be held in the near future in this GRC Phase II proceeding, is an appropriate venue to consider the scope of marginal cost issues that need to be litigated, and any further procedural steps on the issue of marginal costs for fixed charges (and/or a minimum bill) that need to be considered, in this proceeding. The Settling Parties further agree that any marginal cost components (and related factors) developed and adopted in this proceeding for the purpose of future calculations of a potential residential fixed charge (and/or a minimum bill) shall have no precedential value with respect to the revenue allocation or development of non-residential rate design.

(5) Except as specifically described in items 2 and 4, above, nothing in this MC/RA Settlement Agreement shall preclude any Settling Party from advocating for its preferred marginal costs in any other Commission proceeding or for the purpose of addressing specific rate design issues yet to be considered in this or other rate design proceedings.

(6) If the Commission were to adopt new marginal costs/methodologies for setting residential fixed charges (and/or minimum bills), the marginal cost values generated by such new methodologies shall not be used for the purpose of changing the agreed revenue allocation, as set forth Section VIII in this MC/RA Settlement Agreement, or for the purpose of changing rate

design for any non-residential customer.

VIII. REVENUE ALLOCATION SETTLEMENT

1. Revenue Allocation Principles for the Phase II Allocation

The Settling Parties agree that the Phase II revenue allocation to be implemented as a result of this proceeding will be based on the guidance in Table 1, below. Table 1 shows the electric revenue based on present rates as of March 1, 2017, used to prepare this Settlement, the electric revenue that results from this Settlement, and the percentage change for both bundled and Direct Access/Community Choice Aggregation (DA/CCA) customers. The Settling Parties agree that, upon implementation, PG&E will target the average percentage change for every customer group shown in Table 1. The Settling Parties agree that electric revenue should be allocated as a result of the final decision in A.16-06-013 on an overall revenue-neutral basis to preserve then-authorized total authorized revenue requirement (RRQ), except that, as noted below, PG&E will increase then-authorized revenue to include recovery of previously-incurred real time pricing costs. PG&E intends to use 2017 billing determinants and March 1, 2017 Present Rates to determine the allocation, but the actual results may vary based on rate design and sales changes that are implemented with this Phase II proceeding. The Settling Parties agree as follows:

a. The revenue allocation percentages shown in Table 1 establish the basis for the Phase II allocation resulting from this proceeding.

b. The parties agree that rate design changes that may be considered in future settlements in this proceeding will be designed so as not to result in projected revenue shortfalls from any class.

c. There is no agreement on the specific marginal cost values for purposes of revenue allocation. The parties have agreed on “black box” values of marginal costs specifically for the purpose of creating revenue allocation rules as described in part g below.

d. There is no change to the allocation of Nuclear Decommissioning, the Department of Water Resources (DWR) bond charge, the Energy Costs Recovery Amount, the New System Generation Charge (NSGC), Greenhouse Gas Allowance Return, the Competition Transition Charge (CTC), or, for DA/CCA customers, the Power Charge Indifference Adjustment (PCIA).

e. Transmission Owner and other Federal Energy Regulatory Commission (FERC) jurisdictional rates shall be set by the FERC.

f. The allocation of Public Purpose Program (PPP) rates will have two changes:

    1. The CARE surcharge portion of PPP will only change due to the recalculation of the CARE discount. The cost of the CARE discount will be determined based on the difference between CARE and non-CARE rates excluding the CARE surcharge, and the DWR bond charge. This cost will be allocated to eligible customers on an equal cents per kWh basis and collected through the CARE surcharge component of PPP rates. This requires an iterative determination of the CARE surcharge in PG&E's revenue allocation and rate design model.

    2. The other PPP components will be reallocated under a common allocator, replacing the separate allocators in present rates. Upon implementation, PG&E will set the non-CARE surcharge portion of the PPP rate equal to the values in Table 2. These values will then be scaled on an equal percentage basis until the revenue collected by these rates equals the non-CARE surcharge PPP RRQ at the time of implementation.

g. After the allocations of all the revenues described above have been determined, PG&E will seek to create the following bundled and DA/CCA percentage changes agreed to in this proceeding by implementing the following steps:

    Step 1: On a one-time basis, include recovery of previously-incurred real time pricing costs in generation rates ($505,070, plus interest). PG&E will then limit the change to bundled customers' average rate at the class level by applying a cap and floor so that the bundled increase does not exceed 0.7 percent and the bundled decrease is not more than 0.7 percent. The difference in revenues over the cap/floor is then reassigned to bundled generation rates of other customer classes based on their generation marginal cost revenue responsibility.

Step 2: PG&E will limit the change to DA/CCA customers' average rate at the class level by applying a cap and floor so that the DA/CCA increase does not exceed 1.4 percent and the DA/CCA decrease is not more than 1.4 percent. The difference in revenues over the cap/floor is then reassigned to other customer classes based on their respective distribution marginal cost revenue responsibility. While this cap is explicitly applied to limit changes to DA/CCA customers, its effect is also to establish the distribution rate level for both bundled customers and DA/CCA customers since distribution rates for bundled and DA/CCA distribution rates are the same. PG&E's revenue allocation model implements steps 1 and 2 concurrently, and requires multiple iterations of adjusting distribution and generation revenues to ensure the proposed allocations collect the required revenues.

Step 3: At the time this agreement was signed, PG&E's revenue allocation and rate design model showed that the above limits on increases and decreases would result in full collection of PG&E's revenue based on the assumptions used in the model at that time. However, if at the time this Settlement is implemented, the use of these agreed limitations results in revenue adjustments that do not add to zero (i.e., do not collect the then-required revenue), PG&E shall widen the caps and floors for DA/CCA customers and bundled customers in a 2-to-1 ratio until the required revenue can be collected.[9/] These adjustments will be as small as reasonably possible.[10/]

Table 1
Pacific Gas and Electric Company Phase II
Settlement Revenue Allocation Results

Bundled Class	Total Revenue at Present Rates[1]	Total Revenue at Proposed Rates	Percent Change
Residential	$5,142,985,685	$5,119,919,376	-0.45%
Small Light & Power	$1,603,070,115	$1,602,732,161	-0.02%
Medium Light & Power	$1,530,714,453	$1,526,605,670	-0.27%
E-19	$1,577,009,415	$1,580,680,833	0.23%
Streetlight	$61,864,029	$62,297,077	0.70%
Standby	$72,863,103	$72,353,061	-0.70%
Agricultural	$1,071,566,966	$1,079,067,935	0.70%
E-20T	$430,157,436	$433,168,537	0.70%
E-20P	$740,440,546	$743,546,174	0.42%
E-20S	$283,904,226	$283,867,972	-0.01%
Total Bundled	$12,514,575,974	$12,504,238,798	-0.08%

DA/CCA Class	Total Revenue at Present Rates[1]	Total Revenue at Proposed Rates	Percent Change
Residential	$400,212,022	$402,699,475	0.62%
Small Light & Power	$186,172,019	$186,954,598	0.42%
Medium Light & Power	$232,704,726	$234,255,641	0.67%
E-19	$389,461,174	$392,141,900	0.69%
Streetlight	$5,888,112	$5,970,546	1.40%
Standby	$359,449	$354,417	-1.40%
Agricultural	$13,730,454	$13,922,681	1.40%
E-20T	$97,243,296	$98,454,383	1.25%
E-20P	$204,497,496	$205,896,665	0.68%
E-20S	$67,309,012	$67,223,274	-0.13%

9/ If so, PG&E will notify the Settling Parties, for informational purposes only.
10/ Step 3 will not be required if the then-required revenue is fully collected in Steps 1 and 2.

FPP T[2]	$3,926,847	$4,132,142	5.23%
FPP P[2]	$413,173	$426,943	3.33%
FPP S[2]	$2,419,408	$2,500,221	3.34%
Total DA/CCA	$1,604,337,189	$1,614,932,884	0.66%
(1) Present rate revenue is based on rates effective March 1, 2017.			
(2) FPP revenue is combined with E-20, by voltage, for application of caps and floors.			

Table 2
Pacific Gas and Electric Company Phase II
Settlement Proposed PPP Rates

Schedule/Class	Proposed Non-CARE Surcharge PPP Rate
Residential	0.00759
A-1	0.00858
A-6	0.00743
A-15	0.00858
TC-1	0.00080
A-10 T	0.00439
A-10 P	0.00675
A-10 S	0.00711
E-19 T	0.00507
E-19 P	0.00543
E-19 S	0.00622
Streetlights	0.00802
Standby T	0.00423
Standby P	0.01110
Standby S	0.00883
AG-1A, AG-RA, AG_VA, AG-4A, AG-5A	0.01006
AG-1B, AG-RB, AG-VB, AG-4B, AG-4C	0.00871
AG-5B, AG-5C	0.00537
E-20 Firm T	0.00331
E-20 Firm P	0.00490
E-20 Firm S	0.00573

2. Timing of the Phase II Rate Change

It is the intent of the MC/RA Settling Parties that PG&E should be authorized to implement the rate changes resulting from this settlement agreement as soon as practicable, but no sooner than 10 days following the issuance of a final Commission decision approving this agreement. Such rate changes shall also not be made effective earlier than January 1, 2018.

Implementation of the rate changes pursuant to this MC/RA Settlement Agreement on or after January 1, 2018, will be conducted in two steps: (1) allocation pursuant to this agreement based on PG&E's 2017 sales forecast and March 1, 2017 Present Rates; and then (2) allocation of revised revenue requirements pursuant to any subsequent rate changes and the 2018 sales forecast, using the guidelines set forth in Section 3 below, regarding Rate Changes Between General Rate Cases.

3. Rate Changes Between General Rate Cases

After rates are implemented pursuant to the MC/RA Settlement Agreement and the Commission's decision in A.16-06-013, rates will be changed to reflect changes in the revenue requirement in the manner set forth below, until the effective date of implementation of a decision in Phase II of PG&E's next GRC proceeding:

a. Revenue requirement changes between GRCs will be identified by function (e.g., nuclear decommissioning, generation, etc.). Each customer class and schedule will be allocated the average percentage change in functional revenue necessary to collect the functional revenue requirement. This approach to allocating costs using a system average percentage change by function will be employed such that each customer group's share of each functional revenue requirement remains approximately the same. For schedules that are designed together, such as schedules that are designed on a revenue neutral basis, the system average percentage change by function will be applied to the combined rate design group.

b. Generation revenue developed to determine the appropriate starting point to apply the percentages from Section 3 (a) above will exclude directly assigned revenue (i.e., other standby revenue). For the rate changes where there is a change to CTC, current generation revenue used for purposes of allocation will be determined after the change to CTC is incorporated, consistent with current practice.[11/]

c. CTC will be allocated based on the 100 peak hour allocation method. 100 peak hour allocation factors for CTC will be revised each year based on the most recent available information at the time PG&E files its annual Energy Revenue Recovery Energy Resource Recovery Account (ERRA) forecast application consistent with current practice. The NSGC and, for DA/CCA customers, the PCIA will be developed consistent with current practice.[12/]

d. Distribution revenue (including the Conservation Incentive Adjustment) developed to determine the appropriate starting point to apply the percentages from Section (a) above will exclude directly assigned revenue (including, but not limited to, other standby revenue, E-BIP discounts,[13/] streetlight facilities charges, meter charges, employee discounts, and the Schedule A-15 facilities charge) as well as estimated California Alternate Rates for Energy (CARE) program discounts.[14/]

e. PPP rates will be developed as the sum of two pieces[15/] and will be allocated as

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11/ In addition, generation adjustments for SmartRate™ and Peak Day Pricing will be deducted from the generation revenue to be allocated as approved by the Commission.

12/ In A. 17-04-018, PG&E has proposed to replace the PCIA with the Portfolio Allocation Methodology, or PAM. As proposed, PAM and CTC utilize the same allocation and rate design. as is currently used for PCIA and CTC. On June 2, 2017, the Commission established Rulemaking (R.) 17-06-026, and dismissed without prejudice A.17-04-018. Any changes that the Commission makes for PAM or CTC rate design in R. 17-06-026 will take precedence over this settlement.

13/ In A.17-01-012, PG&E has proposed to allocation Schedule E-BIP incentives as a separate revenue requirement. When implemented, PG&E will discontinue direct assignment of discounts associated with Schedule E-BIP.

14/ In compliance with D.16-06-055, in Advice Letter 4893-E-A, PG&E proposed a change to the allocation of the costs of the Self Generation Incentive Program (SGIP). The Commission has not, as yet, acted on that advice letter. Once the CPUC takes action on that advice letter, PG&E will allocate SGIP costs separately based on the method approved by the Commission. Thereafter, for rate changes implementing changes to the SGIP going forward, PG&E will allocate SGIP costs based on whatever is the then-current, Commission-approved SGIP allocation method.

15/ In A.16-11-005, PG&E has proposed a separate charge for the Tree Mortality Program. If approved by the Commission as proposed, this new charge would be calculated as a separate charge and added to PPP rates.

follows:

1. The cost of the CARE program will be determined and the CARE surcharge will be set once per year in the Annual Electric True-Up (AET) proceeding based on the difference between CARE and non-CARE rates.[16/] The cost will be allocated to eligible customers on an equal cents per kWh basis and collected through the CARE surcharge component of PPP rates.
2. The cost of Energy Savings Assistance (ESA), Procurement Energy Efficiency, the Electric Program Investment Charge (EPIC) and the former Public Goods Charge portion of Energy Efficiency will be allocated to customers based on an equal percent of the sum of then-required revenue for these programs (that is, the same percentage will be applied to the then-required revenue for each customer group to determine the allocated revenue).

f. The DWR Bond charge, the Energy Cost Recovery Amount and the Nuclear Decommissioning charge shall continue to be collected on an equal cents per kWh basis for all eligible customers.

g. Transmission Owner and other Federal Energy Regulatory Commission (FERC) jurisdictional rates shall be set by the FERC.

h. Greenhouse gas allowance returns will be set as specified separately by the CPUC.

i. PG&E will continue to make directly assigned adjustments for the Distribution Bypass Deferral Rate Memorandum Account (DBDRMA) in its AET filings. These adjustments will be accomplished as proposed in Advice Letter 3524-E, dated September 15, 2009, and adopted by the Commission in Resolution 4517-E dated December 19, 2013.

16/ The difference between CARE and non-CARE rates include exemptions from the CARE surcharge, the DWR Bond charge, revenues associated with SGIP and the California Solar Initiative, as well as a lower distribution charge.

j. The costs of the Family Electric Rate Assistance (FERA) program will continue to be assigned to the residential class.

k. Should the Commission approve an entirely new revenue requirement category to be included in rates between the effective dates of the 2017 GRC Phase II and the 2020 GRC Phase II decisions, the Settling Parties agree that the revenue allocation and rate design for that new revenue requirement category should be decided by the Commission at that time and that the rules governing existing revenue requirement categories will not govern or be precedential for that purpose.

l. CPUC Fee revenue requirement will be allocated on an equal cents per kWh basis and collected in distribution rates.

IX. AGRICULTURAL SALES VARIABILITY

1. Data Reporting

PG&E shall provide the data listed in Attachment 2 to this Settlement Agreement as set forth therein.

2. Revenue Allocation and Revenue Collection Issues for the Agricultural Class

This Settlement Agreement excludes consideration of Agricultural Parties' claims of deviations between the estimated forecast for Agricultural Class revenue responsibility and revenue collected from the Agricultural Class based on unexpectedly high agricultural sales during recent drought years (prior to 2016), as set forth fully in the "Testimony of Richard McCann and Laura Norin on Behalf of the Agricultural Parties in Pacific Gas & Electric's (PG&E's) 2017 General Rate Case Phase 2 Application Addressing PG&E's Agricultural Class Balancing Account Study" (Agricultural Testimony). Settling Parties agree that this issue will be litigated and subject to the normal litigation process, including rebuttal testimony, hearings if necessary, and briefs. Settling Parties do not waive any rights or arguments on issues of fact or law that have been or may be raised in connection with the Agricultural Testimony on this issue.

X. SETTLEMENT EXECUTION

This Settlement Agreement may be executed in separate counterparts by different Settling Parties hereto and all so executed will be binding and have the same effect as if all the Settling Parties had signed one and the same document. Each such counterparts will be deemed to be an original, but all of which together shall constitute one and the same instrument, notwithstanding that the signatures of all the Settling Parties do not appear on the same page of this Settlement Agreement. This Settlement Agreement shall become effective among the Settling Parties on the date the last Settling Party executes the Settlement Agreement, as indicated below. In witness whereof and intending to be legally bound by the Terms and Conditions of this Settlement Agreement as stated above, the Settling Parties duly execute this Settlement Agreement on behalf of the Settling Parties they represent, as follows:

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2017 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Agricultural Energy Consumers' Association

Michael Boccadoro

By: Michael Boccadoro

Title: Executive Director

Date: 10/25/17

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2017 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

California City-County Streetlight Association

By: ____________________

Title: Attorney for CAL SLA

Date: 10/20/17

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2017 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

California Farm Bureau Federation

By: Karen Norene Mills

Title: Associate Counsel

Date: October 12, 2017

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2017 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

California Large Energy Consumers' Association

By: ____________________
Nora Sheriff

Title: Counsel

Date: 10/03/2017

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2017 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

California Manufacturers & Technology Association

By: ____________________

Title: Counsel for CMTA

Date: 10/13/17

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2017 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

California State University

By: Gregory Klatt

Title: Attorney for California State University

Date: October 24, 2017

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2017 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Direct Access Customer Coalition

By: Daniel W. Douglass
Daniel W. Douglass

Title: Attorney At Law

Date: October 18, 2017

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2017 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Energy Producers and Users Coalition

By: ______________________

Title: Counsel

Date: October 16, 2017

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2017 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Energy Users Forum

By: ______________________

Title: Consultant

Date: 10/17/2017

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2017 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Federal Executive Agencies

By: Rita M Liotta

Title: Counsel

Date: Oct 12, 2017

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2017 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Marin Clean Energy

By: ______________________________

C.C. Song

Title: Senior Policy Analyst

Date: October 24, 2017

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2017 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Office of Ratepayer Advocates

By: [signature]

Title: Director

Date: 10-18-17

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2017 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Pacific Gas and Electric Company

By: Gail L Slocum

Title: Chief Counsel, Regulatory, PG&E

Date: 10/26/17

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2017 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

Small Business Utility Advocates

By: ______________________________
James M. Birkelund

Title: President

Date: October 11, 2017

The undersigned represent that they are authorized to sign on behalf of the Party represented, for the purposes of this 2017 GRC Phase II Marginal Cost and Revenue Allocation Settlement Agreement.

The Utility Reform Network

By: ______________________

Title: Staff Attorney

Date: October 25, 2017

ATTACHMENT 1

Agreed Marginal Costs to be Used Solely for Schedule E-31 and Schedule EDR Purposes

PG&E General Rate Case Phase II
Marginal Cost and Revenue Allocation (MC/RA) Settlement
Attachment 1

The MC/RA Settlement adopts the marginal costs shown in Tables 1 through 5, below, solely for the purpose of establishing costs where needed for customer specific contract analysis, including as required by Schedule E-31 and for analysis of contribution to margin for customers taking service under Schedule EDR.

Generation Marginal Energy Cost

Table 1 Marginal Generation Energy Cost ($/MWh)

Line No.	Transmission	Primary	Secondary
1	$48.91	$49.83	$52.30
2	$37.54	$38.25	$40.14
3	$26.43	$26.93	$28.26
4	$41.09	$41.86	$43.93
5	$23.64	$24.08	$25.27

Marginal Transmission and Distribution Costs

Table 2: 2017 Marginal Transmission Capacity Cost ($/kW-Year)

Line No.	Transmission Capacity
1	7.71

Table 3: Distribution Marginal Customer Access Cost ($/Customer-Year)

Line No.	Class	Access Cost
1	Agricultural B –Small	2,202.82
2	Agricultural B – Large	2,279.20
3	Small L&P – 1 Phase	435.36
4	Small L&P – 3 Phase	1,242.86
5	A10 Medium L&P - Secondary	2,658.13
6	A10 Medium L&P - Primary	4,196.36
7	E19 – Secondary	8,383.77
8	E19 – Primary	7,370.93
9	E19 – Transmission	8,791.61
10	E20 – Secondary	9,203.57
11	E20 – Primary	7,837.67
12	E20 – Transmission	9,981.93

Table 4: Marginal Distribution Capacity Cost by Operating Division

Line No.	Division	Primary Capacity ($/PCAF kW-Year)	New Business on Primary Capacity ($/FLT kW-Year)	Secondary Capacity ($/FLT kW-Year)
1	Central Coast	69.09	14.53	1.04
2	De Anza	35.65	19.66	1.01
3	Diablo	17.78	23.20	1.56
4	East Bay	19.99	18.07	0.88
5	Fresno	39.52	15.81	1.36
6	Humboldt	73.97	14.20	1.12
7	Kern	34.07	16.08	1.23
8	Los Padres	56.49	14.41	1.06
9	Mission	13.63	16.37	0.97
10	North Bay	29.42	14.62	1.75
11	North Valley	53.40	19.23	1.26
12	Peninsula	31.79	14.02	1.06
13	Sacramento	40.91	16.49	1.22
14	San Francisco	40.41	19.69	1.52
15	San Jose	40.12	17.45	1.16
16	Sierra	30.65	20.07	1.25
17	Sonoma	121.98	16.65	1.28
18	Stockton	33.36	15.13	1.34
19	Yosemite	60.18	15.63	1.56
20	System	39.43	16.42	1.25

Table 5: Marginal Distribution Capacity Cost by Distribution Planning Area

Line No.	Division	Distribution Planning Area	Primary Capacity ($/PCAF kW-Year)	New Business on Primary Capacity ($/FLT kW-Year)	Secondary Capacity ($/FLT kW-Year)
1	Central Coast	Carmel Valley 12kV	16.78	14.53	1.04
2	Central Coast	Gonzales	96.93	14.53	1.04
3	Central Coast	Hollister	16.78	14.53	1.04
4	Central Coast	King City	106.36	14.53	1.04
5	Central Coast	Monterey 21kV	16.78	14.53	1.04
6	Central Coast	Monterey 4kV	16.78	14.53	1.04
7	Central Coast	Oilfields	16.78	14.53	1.04
8	Central Coast	Point Moretti	16.78	14.53	1.04
9	Central Coast	Prunedale	16.78	14.53	1.04
10	Central Coast	Salinas	16.78	14.53	1.04
11	Central Coast	Santa Cruz Area	16.78	14.53	1.04
12	Central Coast	Seaside Marina	16.78	14.53	1.04

13	Central Coast	Soledad/Greenfield	16.78	14.53	1.04
14	Central Coast	Watsonville (12/21kV)	158.65	14.53	1.04
15	Central Coast	Watsonville 4kV	16.78	14.53	1.04
16	De Anza	Cupertino	14.07	19.66	1.01
17	De Anza	Los Altos (12kV)	14.07	19.66	1.01
18	De Anza	Los Altos (4kV)	14.07	19.66	1.01
19	De Anza	Los Gatos	14.07	19.66	1.01
20	De Anza	Mountain View	97.10	19.66	1.01
21	De Anza	Sunnyvale	32.48	19.66	1.01
22	Diablo	Alhambra	15.33	23.20	1.56
23	Diablo	Brentwood	15.33	23.20	1.56
24	Diablo	Clayton/Willow Pass	15.33	23.20	1.56
25	Diablo	Concord	33.99	23.20	1.56
26	Diablo	Delta	15.33	23.20	1.56
27	Diablo	Pittsburg	15.33	23.20	1.56
28	Diablo	Walnut Creek 12 kV	15.33	23.20	1.56
29	Diablo	Walnut Creek 21 kV	15.33	23.20	1.56
30	East Bay	K-X	14.93	18.07	0.88
31	East Bay	Oakland C-D-L	14.93	18.07	0.88
32	East Bay	Oakland Edes-J	14.93	18.07	0.88
33	East Bay	Richmond North	14.93	18.07	0.88
34	East Bay	Richmond South	46.97	18.07	0.88
35	Fresno	Auberry	17.27	15.81	1.36
36	Fresno	Central Fresno	17.27	15.81	1.36
37	Fresno	Clovis	40.37	15.81	1.36
38	Fresno	Coalinga	17.27	15.81	1.36
39	Fresno	Corcoran	93.41	15.81	1.36
40	Fresno	Dunlap	17.27	15.81	1.36
41	Fresno	Figarden	17.27	15.81	1.36
42	Fresno	Gates	39.17	15.81	1.36
43	Fresno	Henrietta	72.76	15.81	1.36
44	Fresno	Kerman	107.31	15.81	1.36
45	Fresno	Kettleman	17.27	15.81	1.36
46	Fresno	Kingsburg	54.18	15.81	1.36
47	Fresno	Lemoore	37.10	15.81	1.36
48	Fresno	Mcmullin	17.27	15.81	1.36
49	Fresno	Reedley	17.27	15.81	1.36
50	Fresno	Sanger	17.27	15.81	1.36
51	Fresno	South Fresno	17.27	15.81	1.36
52	Fresno	Stone Corral	17.27	15.81	1.36
53	Fresno	Woodward	52.69	15.81	1.36
54	Humboldt	Arcata	19.66	14.20	1.12
55	Humboldt	Big Lagoon	19.66	14.20	1.12
56	Humboldt	Bridgeville	19.66	14.20	1.12
57	Humboldt	Clearlake (East)	19.66	14.20	1.12
58	Humboldt	Clearlake (West)	157.76	14.20	1.12
59	Humboldt	Eureka	19.66	14.20	1.12
60	Humboldt	Fairhaven	19.66	14.20	1.12
61	Humboldt	Garberville	19.66	14.20	1.12

62	Humboldt	Hopland	19.66	14.20	1.12
63	Humboldt	Maple Creek	19.66	14.20	1.12
64	Humboldt	Mendo Coast (North)	19.66	14.20	1.12
65	Humboldt	Mendo Coast (South)	19.66	14.20	1.12
66	Humboldt	Middletown	19.66	14.20	1.12
67	Humboldt	Newburg/Rio Dell	19.66	14.20	1.12
68	Humboldt	Philo	19.66	14.20	1.12
69	Humboldt	Potter Valley	19.66	14.20	1.12
70	Humboldt	Ukiah Valley	797.17	14.20	1.12
71	Humboldt	Willits	19.66	14.20	1.12
72	Humboldt	Willow Creek	19.66	14.20	1.12
73	Kern	Arvin	97.93	16.08	1.23
74	Kern	Blackwell	15.56	16.08	1.23
75	Kern	Carrizo Plains	15.56	16.08	1.23
76	Kern	Cuyama	15.56	16.08	1.23
77	Kern	Lamont	15.56	16.08	1.23
78	Kern	Lerdo	57.51	16.08	1.23
79	Kern	Mckittrick	15.56	16.08	1.23
80	Kern	Poso Mountain	37.85	16.08	1.23
81	Kern	Taft	15.56	16.08	1.23
82	Kern	Urban Bakersfield East	15.56	16.08	1.23
83	Kern	Urban Bakersfield Northeast	15.56	16.08	1.23
84	Kern	Urban Bakersfield Northwest	15.56	16.08	1.23
85	Kern	Urban Bakersfield Southwest	31.04	16.08	1.23
86	Kern	Wasco	15.56	16.08	1.23
87	Los Padres	Cholame	16.88	14.41	1.06
88	Los Padres	Lompoc	16.88	14.41	1.06
89	Los Padres	North Coast	16.88	14.41	1.06
90	Los Padres	Oceano	16.88	14.41	1.06
91	Los Padres	Paso Robles	121.72	14.41	1.06
92	Los Padres	San Luis Obispo	16.88	14.41	1.06
93	Los Padres	Santa Maria	90.27	14.41	1.06
94	Los Padres	Santa Ynez	16.88	14.41	1.06
95	Los Padres	Sisquoc	16.88	14.41	1.06
96	Mission	Fremont 12 kV	13.63	16.37	0.97
97	Mission	Fremont 21 kV	13.63	16.37	0.97
98	Mission	Hayward 12 kV	13.63	16.37	0.97
99	Mission	Livermore 21 kV	13.63	16.37	0.97
100	Mission	San Ramon - Vineyard	13.63	16.37	0.97
101	Mission	Tri-Valley 12 kV	13.63	16.37	0.97
102	North Bay	Bahia (Or Benicia)	24.85	14.62	1.75
103	North Bay	Marin (Central)	24.85	14.62	1.75
104	North Bay	Marin (Coastal)	24.85	14.62	1.75
105	North Bay	Marin (Northern)	109.78	14.62	1.75
106	North Bay	Marin (Southern)	24.85	14.62	1.75
107	North Bay	Monticello	24.85	14.62	1.75
108	North Bay	Napa	24.85	14.62	1.75

109	North Bay	Silverado	24.85	14.62	1.75
110	North Bay	Vallejo 12 kV	24.85	14.62	1.75
111	North Bay	Vallejo 24 kV	24.85	14.62	1.75
112	North Valley	Antler	17.06	19.23	1.26
113	North Valley	Bogard	17.06	19.23	1.26
114	North Valley	Bucks Creek	17.06	19.23	1.26
115	North Valley	Burney 12 kV	17.06	19.23	1.26
116	North Valley	Cedar Creek	17.06	19.23	1.26
117	North Valley	Chester	17.06	19.23	1.26
118	North Valley	Chico 12 kV	77.82	19.23	1.26
119	North Valley	Clark Road	17.06	19.23	1.26
120	North Valley	Corning 12 kV	17.06	19.23	1.26
121	North Valley	Corning 4 kV	17.06	19.23	1.26
122	North Valley	Elk Creek	17.06	19.23	1.26
123	North Valley	French Gulch	17.06	19.23	1.26
124	North Valley	Grays Flat	17.06	19.23	1.26
125	North Valley	Gridley	17.06	19.23	1.26
126	North Valley	Lake Almanor	17.06	19.23	1.26
127	North Valley	Mcarthur	17.06	19.23	1.26
128	North Valley	Orland	17.06	19.23	1.26
129	North Valley	Oroville 12 kV	17.06	19.23	1.26
130	North Valley	Oroville 4 kV	17.06	19.23	1.26
131	North Valley	Paradise	17.06	19.23	1.26
132	North Valley	Pit #3	17.06	19.23	1.26
133	North Valley	Pit #5	17.06	19.23	1.26
134	North Valley	Quincy	17.06	19.23	1.26
135	North Valley	Red Bluff	208.21	19.23	1.26
136	North Valley	Redding 12 kV	17.06	19.23	1.26
137	North Valley	Rising River 12 kV	17.06	19.23	1.26
138	North Valley	Volta	17.06	19.23	1.26
139	North Valley	Whitmore	17.06	19.23	1.26
140	North Valley	Wildwood	17.06	19.23	1.26
141	North Valley	Willows	17.06	19.23	1.26
142	Peninsula	Central Peninsula 12 kV	15.57	14.02	1.06
143	Peninsula	Central Peninsula 21 kV	15.57	14.02	1.06
144	Peninsula	Central Peninsula 4 kV	15.57	14.02	1.06
145	Peninsula	North Pen East 12 kV	15.57	14.02	1.06
146	Peninsula	North Pen East 4 kV	15.57	14.02	1.06
147	Peninsula	North Pen West 12 kV	15.57	14.02	1.06
148	Peninsula	Peninsula Total	15.57	14.02	1.06
149	Peninsula	South East Peninsula 12 kV	33.88	14.02	1.06
150	Peninsula	South Peninsula 4 kV	15.57	14.02	1.06
151	Peninsula	South West Peninsula 12kV	112.45	14.02	1.06
152	Peninsula	West Peninsula 12 kV	15.57	14.02	1.06
153	Sacramento	Davis	77.64	16.49	1.22
154	Sacramento	Grand Island	16.11	16.49	1.22
155	Sacramento	North Colusa	415.15	16.49	1.22
156	Sacramento	Peabody	16.11	16.49	1.22
157	Sacramento	South Colusa	16.11	16.49	1.22

158	Sacramento	Suisun/Cordelia	46.85	16.49	1.22
159	Sacramento	Vacaville	16.11	16.49	1.22
160	Sacramento	West Sacramento	16.11	16.49	1.22
161	Sacramento	Woodland	16.11	16.49	1.22
162	Sacramento	Yolo Ag (North)	16.11	16.49	1.22
163	Sacramento	Yolo Ag (West)	16.11	16.49	1.22
164	Sacramento	Yolo/Colusa River Ag	16.11	16.49	1.22
165	San Francisco	Embarcadero	18.68	19.69	1.52
166	San Francisco	Hunter's Point	18.68	19.69	1.52
167	San Francisco	Larkin	1,988.54	19.69	1.52
168	San Francisco	Martin	83.14	19.69	1.52
169	San Francisco	Mission	18.68	19.69	1.52
170	San Francisco	Potrero	18.68	19.69	1.52
171	San Jose	Downtown San Jose 12 kV	14.71	17.45	1.16
172	San Jose	Downtown San Jose 4 kV	14.71	17.45	1.16
173	San Jose	East San Jose	185.98	17.45	1.16
174	San Jose	Evergreen	14.71	17.45	1.16
175	San Jose	Milpitas 12 kV	14.71	17.45	1.16
176	San Jose	Milpitas 21 kV	14.71	17.45	1.16
177	San Jose	Morgan Hill/Gilroy	21.21	17.45	1.16
178	San Jose	North San Jose 12 kV	14.71	17.45	1.16
179	San Jose	North San Jose 21 kV	22.43	17.45	1.16
180	San Jose	South San Jose 12 kV	14.71	17.45	1.16
181	San Jose	South San Jose 21 kV	62.52	17.45	1.16
182	San Jose	West San Jose	14.71	17.45	1.16
183	Sierra	Alleghany	16.15	20.07	1.25
184	Sierra	Apple To Echo	16.15	20.07	1.25
185	Sierra	Bear River	49.18	20.07	1.25
186	Sierra	Bonnie Nook/Shady Glen	16.15	20.07	1.25
187	Sierra	Central Nevada	16.15	20.07	1.25
188	Sierra	Clarksville/Shingle Springs	16.15	20.07	1.25
189	Sierra	Columbia Hill	16.15	20.07	1.25
190	Sierra	Diamond Spr/Placerville	16.15	20.07	1.25
191	Sierra	Donner Summit	16.15	20.07	1.25
192	Sierra	Forest Hill	16.15	20.07	1.25
193	Sierra	Horseshoe	16.15	20.07	1.25
194	Sierra	Lincoln	27.25	20.07	1.25
195	Sierra	Marysville	16.15	20.07	1.25
196	Sierra	Mountain Quarries	16.15	20.07	1.25
197	Sierra	Narrows	16.15	20.07	1.25
198	Sierra	North Placer	16.15	20.07	1.25
199	Sierra	Pike	16.15	20.07	1.25
200	Sierra	South Placer	55.97	20.07	1.25
201	Sierra	Yuba City	16.15	20.07	1.25
202	Sierra	Yuba Foothills	16.15	20.07	1.25
203	Sonoma	Bellevue/Cotati	64.11	16.65	1.28
204	Sonoma	Cloverdale	19.23	16.65	1.28
205	Sonoma	Fitch Mountain/Fulton	282.83	16.65	1.28
206	Sonoma	Petaluma 12 kV	19.23	16.65	1.28

207	Sonoma	Petaluma 4 kV	19.23	16.65	1.28
208	Sonoma	Santa Rosa	19.23	16.65	1.28
209	Sonoma	Sebastopol	19.23	16.65	1.28
210	Sonoma	Sonoma	19.23	16.65	1.28
211	Sonoma	Sonoma Coast	19.23	16.65	1.28
212	Stockton	Angels Camp	17.73	15.13	1.34
213	Stockton	Clay	17.73	15.13	1.34
214	Stockton	Corral	17.73	15.13	1.34
215	Stockton	Jackson	17.73	15.13	1.34
216	Stockton	Linden 12 kV	403.54	15.13	1.34
217	Stockton	Lodi 12 & 21 kV	17.73	15.13	1.34
218	Stockton	Manteca 17 kV	57.28	15.13	1.34
219	Stockton	Middle River	17.73	15.13	1.34
220	Stockton	North Stockton 12 kV	17.73	15.13	1.34
221	Stockton	North Stockton 21 kV	17.73	15.13	1.34
222	Stockton	North Stockton 4 kV	17.73	15.13	1.34
223	Stockton	Salt Springs	17.73	15.13	1.34
224	Stockton	South Stockton 12 kV	17.73	15.13	1.34
225	Stockton	South Stockton 4 kV	17.73	15.13	1.34
226	Stockton	Tracy 12 kV	17.73	15.13	1.34
227	Yosemite	Atwater	20.80	15.63	1.56
228	Yosemite	Canal	103.79	15.63	1.56
229	Yosemite	Chowchilla	92.00	15.63	1.56
230	Yosemite	Indian Flat	20.80	15.63	1.56
231	Yosemite	Mariposa	20.80	15.63	1.56
232	Yosemite	Mendota	81.98	15.63	1.56
233	Yosemite	Merced 12 kV	30.11	15.63	1.56
234	Yosemite	Merced 21 kV	20.80	15.63	1.56
235	Yosemite	Merced Falls	445.53	15.63	1.56
236	Yosemite	Newhall	20.80	15.63	1.56
237	Yosemite	Newman	20.80	15.63	1.56
238	Yosemite	Oakdale	99.91	15.63	1.56
239	Yosemite	Oakhurst	20.80	15.63	1.56
240	Yosemite	Oro Loma	20.80	15.63	1.56
241	Yosemite	Rio Mesa	20.80	15.63	1.56
242	Yosemite	Sonora	20.80	15.63	1.56
243	Yosemite	Spring Gap	20.80	15.63	1.56
244	Yosemite	Storey	20.80	15.63	1.56
245	Yosemite	Westley	20.80	15.63	1.56
246	System		39.43	15.13	1.34

ATTACHMENT 2

Agreed Data Relating to Agricultural Sales Variability Issues

PG&E General Rate Case Phase II
Marginal Cost and Revenue Allocation (MC/RA) Settlement
Attachment 2

Agricultural Data Reporting Requirements

Background

In Application (A.) 16-06-013, Phase II of PG&E's General Rate Case (GRC), the Agricultural Energy Consumers Association (AECA) and the California Farm Bureau Federation (CFBF) assert:

> Dry years can result in significant overcollections from agricultural customers and revenue reductions for other customers, with the opposite true in wet years. Based on the evidence presented in this proceeding, the Commission should explicitly acknowledge this flaw in PG&E's current methodology.[1]

PG&E agrees that adopted agricultural sales forecasts can vary (and have varied) significantly from actual sales. This was particularly apparent during the recent drought. Further, the Parties have agreed that some data tracking should be performed, which can then be considered in the 2020 GRC Phase II proceeding. Accordingly, PG&E has agreed to develop information as specified below in Sections A, B and C, subject to the following conditions:

1. No agreement has been reached with regard to whether rate adjustments should be made as a result of the information that will be tracked and provided. However, any party may use this information in the manner it deems appropriate for litigation of relevant issues in Phase II of PG&E's 2020 GRC.
2. Tracking shall consist of provision of data as set forth in Parts A and B, below, and shall start with 2016. In addition, limited historical data on agricultural demand specified in Part C, below, will be provided for the period 2008-2015.

Part D sets forth the timeframe for providing the listed data.

A. Generation Data Tracking

1) Forecast Data from Advice Letters[2]
   a) Forecasts of bundled sales and DA/CCA sales for each agricultural rate schedule (excluding E-37 customers) from the Annual Electric True Up Advice Letter (AET)
   b) Forecasts of system total bundled sales and DA/CCA sales from the AET

[1] Testimony of Richard McCann and Laura Norin on Behalf of the Agricultural Parties in PG&E's 2017 GRC Phase 2 Application Addressing PG&E's Agricultural Class Balancing Account Study, page 29.
[2] For agricultural class data, advice letter data will be adjusted to remove Schedule E-37 from the agricultural class.

c) Forecasts of generation revenue and Power Charge Indifference Adjustment (PCIA) revenue[3] from each agricultural rate schedule (excluding E-37 customers) from the AET and any other advice letters that modify the generation or PCIA rate
d) Forecasts of total generation revenue and PCIA revenue from the AET and any other advice letters that modify the generation or PCIA rate
e) Average generation rates and PCIA rates for each agricultural rate schedule (excluding E-37 customers) from the AET and any other advice letters that modify the generation or PCIA rate
f) System-average generation rate and PCIA rate from the AET and any other advice letters that modify the PCIA rate

2) Recorded Data Used as the Base Year for the 2014 and 2017 GRC Phase II Proceedings
   a) Recorded hourly bundled sales and DA/CCA sales for each agricultural rate schedule consistent with the forecast used in the adopted GRC Phase II revenue allocation
   b) Recorded PG&E system total hourly bundled sales and DA/CCA sales consistent with the forecasts used in the adopted GRC Phase II revenue allocation
   c) Recorded summer and winter generation Peak Capacity Allocation Factors (PCAFs) for each rate schedule consistent with the adopted GRC Phase II revenue allocation
   d) Recorded summer and winter bundled sales and DA/CCA sales for each rate schedule

3) Forecast Data from GRC Phase II
   a) Total summer and winter bundled sales and DA/CCA sales for each rate schedule consistent with the forecast used in the adopted GRC Phase II revenue allocation for each year of the GRC cycle
   b) Generation revenue allocations adopted for each agricultural rate schedule in the GRC Phase II proceeding
   c) System-total generation revenue adopted in the GRC Phase II proceeding

4) Recorded Data during the Tracking Period
   a) Monthly bundled sales and DA/CCA sales for each rate schedule
   b) Hourly bundled sales for each agricultural rate schedule, where available
   c) Hourly DA/CCA sales for each agricultural rate schedule, where available
   d) Hourly PG&E system-total bundled sales, where available
   e) Hourly PG&E total DA/CCA sales, where available
   f) DA/CCA PCIA revenue from each agricultural rate schedule
   g) Total PCIA revenue
   h) Bundled generation revenue from each agricultural rate schedule
   i) Total bundled generation revenue
   j) Summer and winter generation PCAFs for each rate schedule
   k) Bundled agricultural demand from each rate schedule, as available based on billing data:
      i) Maximum demand summer

[3] References to the PCIA incorporate any PCIA successor charge that may be adopted.

ii) Maximum demand winter
iii) Maximum peak demand summer
iv) Maximum part-peak demand summer
v) Maximum part-peak demand winter

B. Distribution Tracking

1) Forecast Data from Advice Letters[4]
   a) Average distribution rate for each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the distribution rate
   b) Distribution revenue from each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the distribution rate
   c) System-average distribution rate from the AET and any other advice letters that modify the distribution rate
   d) System total distribution revenue from the AET and any other advice letters that modify the distribution rate
   e) Average New System Generation Charge (NSGC) rate for each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the NSGC rate
   f) Total NSGC revenue from each agricultural rate schedule (excluding E-37) from the AET and any other advice letters that modify the NSGC rate
   g) System-average NSGC rate from the AET and any other advice letters that modify the NSGC rate
   h) System total NSGC revenue from the AET and any other advice letters that modify the NSGC rate

2) Recorded Data Used as the Base Year for the 2014 and 2017 GRC Phase II Proceedings
   a) Recorded summer and winter distribution PCAFs for each rate schedule consistent with the forecast used in the adopted GRC Phase II revenue allocation
   b) Recorded Final Line Transformer (FLT) load for each rate schedule consistent with the forecast used in the adopted GRC Phase II revenue allocation

3) Forecast Data from GRC Phase II
   a) Distribution revenue allocations adopted for each agricultural rate schedule in the GRC Phase II proceeding
   b) System-total distribution revenue adopted in the GRC Phase II proceeding

4) Recorded data during the Tracking Period:
   a) Number of meters (averaged over period) for each agricultural rate schedule
   b) Number of new connects for each agricultural rate schedule
   c) Number of disconnects for each agricultural rate schedule
   d) Summer and winter distribution PCAFs for each rate schedule
   e) Distribution FLTs for each rate schedule

[4] For agricultural class data, advice letter data will be adjusted to remove Schedule E-37 from the agricultural class.

f) Distribution agricultural demand from each rate schedule, as available based on billing data:
   i) Maximum demand summer
   ii) Maximum demand winter
   iii) Maximum peak demand summer
   iv) Maximum part-peak demand summer
   v) Maximum part-peak demand winter
g) Distribution revenue from each agricultural rate schedule
h) System-total distribution revenue
i) NSGC revenue from each agricultural rate schedule
j) System-total NSGC revenue

C. Historical Demand Data (to be provided on an annual basis for the 2008-2015 period for each agricultural rate class/schedule)

1) Generation demand, as available based on billing data:
   a) Maximum demand summer
   b) Maximum demand winter
   c) Maximum peak demand summer
   d) Maximum part-peak demand summer
   e) Maximum part-peak demand winter
   f) Summer and winter generation PCAFs, using class definitions in place at the time for each year[5]

2) Distribution demand, as available based on billing data:
   a) Maximum demand summer
   b) Maximum demand winter
   c) Maximum peak demand summer
   d) Maximum part-peak demand summer
   e) Maximum part-peak demand winter
   f) Summer and winter distribution PCAFs, using class definitions in place at the time for each year
   g) Distribution FLT load, using class definitions in place at the time for each year

D. Data Reporting

1) Historical demand data specified in Part C will be provided to AECA and CFBF in a spreadsheet format within six months of the date of a Commission decision approving this settlement. Notice of the availability of historical demand data will be provided to the California Large Energy Consumers' Association (CLECA) and the Energy Producers and Users Coalition (EPUC). The notice will identify

[5] PG&E will identify which rate schedules are included in each class definition for the historic PCAF and FLT data.

what data is being provided by reference to the alpha and numerical designations in this [*AG sales variability data agreement, substitute final name*], and the year of the data.

2) Tracking data specified in Sections A and B will be reported to AECA and CFBF annually in a spreadsheet format, lagged by at least 90 days, or as the data become available. If data will not be available within the 90-day target, notification will be sent to AECA and CFBF specifying a date when the data will be provided. Notice of the availability of tracking data will be provided to CLECA and to EPUC. The notice will identify what data is being provided by reference to the alpha and numerical designations in this [*AG sales variability data agreement, substitute final name*], and the year of the data. Tracking data for 2016 may be provided simultaneously with the 2017 tracking data.
3) Annual reports for the Tracking period from 2016 through the latest year available (likely to be 2017) will be provided as part of PG&E's 2020 GRC Phase II application.
4) Tracking data will continue to be provided for the 2018 and 2019 data years. Notice of the availability of tracking data will be provided to CLECA and to EPUC. The notice will identify what data is being provided by reference to the alpha and numerical designations in this [*AG sales variability data agreement, substitute final name*], and the year of the data.

E. Confidentiality

1) Customer specific information shall be anonymized and aggregated to meet the Commission's aggregation requirements in D.14-05-016, at a minimum. Where the aggregation standards cannot be met, the customer information will be anonymized, and access to the anonymized information will be treated as confidential and provided pursuant to the 2017 GRC II NDA to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case. If it is still possible to identify the customer given the anonymized information, the customer information will not be provided to anyone except Commission staff.
2) PG&E may designate other confidential information as subject to the non-disclosure agreement, and the information will only be provided to the party and its consultants who have executed the non-disclosure agreement for the 2017 GRC II case, and as consistent with the terms of that NDA. Any information provided under this agreement that PG&E designates as subject to the NDA will be clearly marked with this designation.
3) With respect to confidential data provided under this [*AG sales variability data agreement, substitute final name*], PG&E will not send the notice provided under Section 5 of the 2017 GRC II NDA before issues for which the data is used in PG&E's next GRC II case are resolved there.
4) Submission or use of confidential data that was received pursuant to this agreement for PG&E's next GRC II case will require appropriate confidentiality protections in that case, including NDAs and/or motions for confidential treatment in that docket. Examples would be testimony, work papers, data responses, reports, etc., that include confidential information.